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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

GARY PIERCE, Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

Arizona Corporation Commission
DOCKETED
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IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	Docket No. E-01345A-11-0224 **NOTICE OF FILING DIRECT TESTIMONY (COST OF SERVICE AND RATE DESIGN) AND ATTACHMENTS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT-MCMORAN COPPER & GOLD INC. AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**

Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition (collectively "AECC"), hereby submit the Direct Testimony (Cost of Service and Rate Design) and Attachments of Kevin C. Higgins on behalf of AECC in the above captioned Docket.

RESPECTFULLY SUBMITTED this 2nd day of December 2011.

FENNEMORE CRAIG, P.C.

By
C. Webb Crockett
Patrick J. Black
3003 N. Central Avenue, Ste. 2600
Phoenix, AZ 85012-2913

Attorneys for Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition

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FENNEMORE CRAIG
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1200 West Washington
Phoenix, Arizona 85007

COPY of the foregoing was **HAND-DELIVERED/ MAILED/EMAILED** this 2nd day of December 2011 to:

Lyn Farmer
Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Janice Alward, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Steve M. Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Meghan H. Grabel
Thomas L. Mumaw
PINNACLE WEST CAPITAL CORPORATION
400 North 5th Street
P.O. Box 53999, Ms 8695
Phoenix Arizona 85072-3999
Attorneys for Arizona Public Service Company

Daniel W. Pozefksy
RUCO
1110 W. Washington St., Suite 220
Phoenix, AZ 85007

Michael A. Curtis
William P. Sullivan
Melissa A. Parham
CURTIS, GOODWIN, SULLIVAN, UDALL & SCHWAB, P.L.C.
501 E. Thomas Road
Phoenix, Arizona 85012
Attorneys for Town of Wickenburg

Timothy M. Hogan
ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST
202 E. McDowell Rd., Suite 153
Phoenix, Arizona 85004
Attorneys for WRA, SWEEP, ASBA/AASBO

David Berry
WESTERN RESOURCE ADVOCATES
PO Box 1064
Scottsdale, Arizona 85252

Barbara Wyllie-Pecora
14410 West Gunsight Drive
Sun City West, Arizona 85375

Kurt J. Boehm
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
Attorneys for The Kroger Co.

John William Moore, Jr.
7321 North 16th Street
Phoenix, Arizona 85020

Jeffrey W. Crockett
BROWNSTEIN HYATT FARBER SCHRECK LLP
40 North Central Avenue, 14th Floor
Phoenix, Arizona 85004
Attorneys for Arizona Association of Realtors

Michael W. Patten
ROSHKA DEWULF & PATTEN, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004
Attorneys for Tucson Electric Power Company

Bradley S. Carroll
TUCSON ELECTRIC POWER COMPANY
One South Church Avenue, Suite UE 201
Tucson, Arizona 85701

Cynthia Zwick
1940 East Luke Avenue
Phoenix, Arizona 85016

Michael M. Grant
GALLAGHER & KENNEDY, PA
2575 E. Camelback Road
Phoenix, Arizona 85016
Attorneys for AIC

Gary Yaquinto
ARIZONA INVESTMENT COUNCIL
2100 N. Central Avenue, Suite 210
Phoenix, Arizona 85004

Karen S. White
AIR FORCE UTIITY LAW FIELD SUPPORT CENTER
AFLOA/JACL-ULFSC
149 Barnes Drive
Tyndall AFB, Florida 32403

Greg Patterson
MUNGER CHADWICK
2390 E. Camelback Road, Suite 240
Phoenix, Arizona 85016
Attorneys for Arizona Competitive Power Alliance

Nicholas J. Enoch
Jarrett J. Haskovec
LUBIN & ENOCH, PC
349 N. Fourth Avenue
Phoenix, Arizona 85003
Attorneys for IBEW Locals 387, 640 & 769

Lawrence V. Robertson, Jr.
PO Box 1448
Tubac, Arizona 85646
Attorney for Southwestern Power Group II, LLC; Bowie Power Station, LLC; Noble Americas Energy Solutions LLC; Constellation NewEnergy, Inc.; Direct Energy, LLC and Shell Energy North America (US), LP

Laura E. Sanchez
NATURAL RESOURCES DEFENSE COUNCIL
PO Box 287
Albuquerque, New Mexico 87103

Jay I. Moyes
Steve Wene
MOYES SELLERS & HENDRICKS
1850 N. Central Avenue, Suite 1100
Phoenix, Arizona 85004
Attorneys for AzAg Group

Jeffrey J. Woner
K.R. SALINE & ASSOC., PLC
160 N. Pasadena, Suite 101
Mesa, Arizona 85201

Scott S. Wakefield
RIDENOUR, HIENTON & LEWIS, PLLC
201 N. Central Avenue, Suite 3300
Phoenix, Arizona 85004
Attorneys for Wal-Mart Stores, Inc.

Steve W. Chriss
Wal-Mart Stores, Inc.
2011 S.E. 10th Street
Bentonville, Arkansas 72716

Mel Bear
4108 West Calle Lejos
Glendale, Arizona 85310

Craig A. Marks
CRAIG A. MARKS, PLC
10645 N. Tatum Boulevard
Suite 200-676
Phoenix, Arizona 85028
Attorney for AARP

Douglas V. Fant
LAW OFFICES OF DOUBLAS V. FANT
3655 W. Anthem Way
Suite A-109, PMB 411
Anthem, Arizona 85086

Amanda Ormond
INTERWEST ENERGY ALLIANCE
76630 S. McClintock Drive
Suite 103-282
Tempe, Arizona 85284

By: W. M. McCracken

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BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona	)	
Public Service Company for a Hearing to	)	
Determine the Fair Value of the Utility	)	
Property of the Company for Ratemaking	)	Docket No. E-01345A-11-0224
Purposes, to Fix a Just and Reasonable	)	
Rate of Return Thereon, to Approve Rate	)	
Schedules Designed to Develop Such Return	)	

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Cost of Service / Rate Design

December 2, 2011

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who previously filed testimony on the subject of revenue requirements in this proceeding on behalf of Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC")?[1]

A. Yes, I am. My qualifications are presented in Appendix A attached to that direct testimony.

OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your testimony in this cost-of-service and rate design phase of the proceeding?

A. My testimony addresses APS's proposed rate spread, rate design, and cost of service analysis.

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that APS's cost of service study be adopted by the Commission. The Average and Excess Demand method employed by APS to allocate production plant costs fully meets the Commission's stated objectives in Decision No. 69663. Further, APS's allocation of energy costs based on customer class hourly load shapes and their relationship to hourly energy prices is fundamentally reasonable. This approach properly aligns cost responsibility with cost causation, and therefore is inherently equitable.

(2) APS's proposed spread of its rate increase focuses exclusively on base rates. This is not the proper basis for rate spread determination because the sizable credit in the Power Supply Adjustor ("PSA") is being reset to near zero when new rates take effect. By itself, this PSA Reset has the effect of increasing rates (on average) over 5 percent. The impact of the PSA Reset is even greater on industrial customers – around 8 percent. This impact must be added to the base rate increase and taken into account in determining the equitable spread of rates across customer classes.

(3) APS's proposed rate spread largely ignores cost of service ratemaking principles, while greatly expanding the very sizable subsidy that General Service customers pay to Residential customers to $124 million per year. I recommend that the Company's rate spread be rejected in favor of an approach that balances the ratemaking objectives of adherence to cost-of-service principles and gradualism. Specifically, I recommend a five-step approach that: (a) moves

Residential rates halfway to cost-of-service; (b) caps the rate impact on all classes to no more than 5 percentage points above the average percentage increase (taking account of the PSA Reset); (c) sets rates for Rate Schedules E-34 and E-35 equal to cost-of-service; (d) funds the residential subsidy through an equal percentage increase on the subsidy-paying classes; and (e) smoothes out the rate impact within the E-32 customer group.

(4) I recommend that APS's proposed Interruptible Rate Rider be approved with two modifications: (a) changing the basis of the proposed credit paid to participating customers from "50% demand / 50% energy" as proposed by APS to "100% demand," and (b) including in the Rider a multiyear schedule of capacity rates, rather than a single rate that will stand until the next general rate case.

(5) I recommend that Experimental Rate Rider AG-1 be approved by the Commission, but the requirement to pay a Reserve Capacity Charge should be removed. I also recommend that Experimental Rate Rider AG-1 should not be viewed as a substitute for reinstating full direct access service in Arizona.

(6) I recommend approval of APS's proposal to change the rate design of Rate Schedule 32-L by removing the first tier energy charge for this rate schedule, modifying the remaining energy charge to reflect the average energy cost per kWh, and revising the demand charge to include the implicit demand-related costs that are currently recovered through the first tier energy charge.

(7) APS's proposed rate design for Rate Schedules E-34 and E-35 should be rejected, as it fails to properly take account of the implications of the PSA Reset, and would unduly increase the net energy charge in these rate schedules to

the detriment of the higher-load-factor customers served on them. Instead, I recommend that the energy charge for these two rate schedules be set equal to the current base energy rate *minus* the amount of the current credit in the Forward Component of the PSA. As fuel costs are declining, the energy charges for E-34 and E-35 customers should not be increased above this level. The revenues to support this rate design would not come from customers on other rate schedules, but from increasing the E-34 and E-35 demand charges to the level sufficient to recover the targeted revenue requirement for these two rate schedules.

COST OF SERVICE

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- Separating the utility's costs in accordance with the various *functions* of its system (e.g., generation [or production], transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for the utility's costs to the various customer classes based on principles of cost causation.

Q. What is the role of cost-of-service analysis in setting rates?

A. Each of the three steps above has an important role in the ratemaking process. If rates are unbundled by function, as they are in Arizona, then separating the utility's costs by function is important in determining which costs are generation-related, transmission-related, and distribution-related.

The classification of costs is critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes is important for determining revenue apportionment across customer classes, also called "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization. For these reasons, the results of the class cost-of-service analysis should be given very strong weighting in guiding the proper revenue apportionment.

Q. What approach has APS used for allocating generation plant costs between APS retail customers and FERC-jurisdictional customers?

A. As explained in the direct testimony of APS witness Zachary J. Fryer, APS uses the 4-Coincident Peaks ("4-CP") method for allocating generation plant costs between its state and federal jurisdictional loads. The 4-CP method allocates fixed production costs based on the average of system peak demands in the four summer months, which is when APS's production capacity requirements are determined.

Q. In your opinion, is the 4-CP method appropriate for allocating APS's jurisdictional generation plant costs?

A. Yes, it is. APS's maximum system demands are driven by summer usage. Given the characteristics of APS's system, the 4-CP method properly aligns the allocation of the Company's fixed costs with cost causation. As noted by Mr. Fryer, the 4-CP method is used by APS in its cases before FERC.

Q. **Does APS also use the 4-CP method for allocating generation plant costs across its retail customer classes in this case?**

A. No. APS uses the Average and Excess Demand method for that purpose. This method was used in APS's previous rate case and was adopted in response to the directives and guidance from the Commission in Decision No. 69633 in Docket No. E-01345A-05-0816. [Decision at 70-71]

Q. **Do you agree with APS's use of the Average and Excess Demand method for allocating the cost of production plant cost among customer classes?**

A. Yes, I do. The Average and Excess Demand method is described in the NARUC Manual in its section entitled "Energy Weighting Methods" and fully meets the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[2]

Q. **How does the Average and Excess Demand method apportion responsibility for incremental production plant that is required to meet loads that are above average demand?**

[2] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.

A. The Average and Excess Demand method allocates the cost of capacity above average demand in proportion to each class's excess demand, where excess demand is measured as the difference between each class's individual peak demand[3] and its average demand. In this manner, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

Q. Is the Average and Excess Demand method used in any neighboring jurisdictions?

A. Yes. This method is utilized by the Salt River Project, Public Service Company of Colorado, and El Paso Electric Company in Texas.

Q. How does APS allocate energy costs across customer classes?

A. Consistent with its filing in its previous general rate case, APS allocates energy costs based on customer class hourly load shapes and their relationship to hourly energy prices, which produces a weighted energy cost for each class. This approach is a great improvement over the method that had been used for allocating energy costs prior to the last APS rate case; prior to that case, each kilowatt-hour was assigned exactly the same average cost irrespective of whether it occurred during the high-cost, summer on-peak periods, or a lower-cost, off-peak periods.

Q. Do you support APS's use of a weighted energy cost for each customer class based on the class's hourly load shape?

[3] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

A. Yes. This approach properly aligns cost responsibility with cost causation, and therefore is inherently equitable.

Q. What is your overall recommendation concerning APS's cost-of-service methodology in this proceeding?

A. For the reasons discussed above, I recommend that the method used by APS for production cost-of-service be approved by the Commission.

Q. Did you conduct any cost-of-service analysis in addition to what APS has presented?

A. Yes. APS's cost-of-service analysis presents the revenue deficiency for each customer class at an equalized rate of return for <u>base</u> rates. While this is a useful piece of information, it only tells part of the story: APS's sole focus on base rates ignores the implications of resetting the Forward Component of the PSA, which is currently a credit, to zero. The PSA Reset will occur when new base rates go into effect. To understand more fully the implications of APS's cost-of-service study results, it is also necessary to indentify each customer class's revenue deficiency and rate impacts *after* taking account of the PSA credits in current rates and the knowledge that the PSA will be reset. Such an analysis does not undo the APS study, but simply provides more information to present a more complete picture.

In Attachment KCH-6, page 1, I present class returns and revenue deficiencies based on APS's cost-of-service study for base rates only. On page 2 of this attachment, I present the class revenue deficiencies after taking account of the PSA Credit Reset that will accompany rate implementation. The results of this analysis are summarized in Table KCH-2, below.[4]

Table KCH-2

APS Cost-of-Service Results
Percentage rate change required to bring each class to cost-of-service at APS's proposed revenue requirement

Class	Required Base Rate Change	Rate Change Inc. Reset of PSA Credit
Residential	12.40%	17.66%
General Service	(6.80)%	(1.27)%
E-20	24.60%	31.18%
E-32 (total)	(8.13)%	(3.03)%
E-32 TOU	(11.13)%	(5.07)%
E-30, E-32XS, S	(11.35)%	(7.35)%
E-32M	(6.69)%	(1.25)%
E-32L	(4.09)%	2.46%
E-34	(0.25)%	7.47%
E-35	0.95%	9.69%
Water Pumping	9.18%	16.47%
Street Lighting	11.19%	15.33%
Dusk-to-Dawn	(2.52)%	(0.98)%
Total	3.33%	8.77%

Q. Please explain the "Required Base Rate Change" column in Table KCH-2.

A. This column shows the percentage change in base rates that each customer class would need to experience in order to pay rates equal to each class's cost of service at APS's proposed revenue requirement in this proceeding. The percentages in this column focus exclusively on changes in base rates; thus, the rate impact in this column ignores the fact that customers currently receive a substantial credit through the PSA Adjustor, the forward-looking component of

[4] This table is enumerated KCH-2 as Table KCH-1 is incorporated in my revenue requirement testimony.

which will be reset to zero. In other words, the change in base rates being shown does not reflect the impact experienced by customers from the loss of the PSA credit.

Q. **Please explain the "Rate Change Inclusive of Reset of PSA Credit" column in Table KCH-2.**

A. This column shows the percentage change in rates that each customer class would need to experience in order to pay rates equal to each class's cost of service at APS's proposed revenue requirement in this proceeding – after taking into consideration that customers are currently receiving a PSA credit equal to $0.005658/kWh – and that the forward-looking component of the PSA will be reset to zero when the new Base Fuel Rate takes effect.[5] The loss of this credit means that the net rate impact on customers from APS's proposed revenue requirement is significantly larger than the base rate increase viewed in isolation.

Q. **After taking account of the PSA credit being reset to zero, what is the net retail rate impact on APS customers from APS's proposed base rate increase?**

A. As shown in Attachment KCH-6, page 2, column (h) the net retail rate increase from APS's proposed base rate increase (as filed) and the resetting of the PSA credit to zero is $239 million, or 8.77% on an overall basis.

Q. **But isn't part of APS's proposed base rate increase comprised of $44.9 million in solar generation plant additions costs that would be recovered**

[5] The current PSA credit of $0.005658/kWh is comprised of a Forward Component of $0.002642/kWh and an Historical Component of $0.003016/kWh. In its rate impact analysis, APS uses going-forward estimates of the PSA credit equal to $0.000014 for the Forward Component (effectively zero) and 0.000461/kWh for the Historical Component. Source: APS response to Staff 3.065, Attachment CAM-14, p. 3.

from customers anyway through the RES Tariff if they were not shifted into base rates as proposed by APS?

A. Yes. But in ascertaining the rate impact faced by customers from bringing (all or part of) the solar plant additions costs into base rates, it is important to distinguish between those solar plant additions costs that are eligible (or approved) for *future* recovery through the RES Tariff and the recovery of these solar generation costs actually in current RES rates. Most of the solar plant additions costs at issue in this case are not yet being recovered through the RES Tariff – indeed only about $14.6 million of the $44.9 million in solar generation plant additions costs that APS is proposing for inclusion in base rates is being recovered through the 2011 RES Adjustor.[6] Thus, the recovery of the remaining $30.3 million in solar plant addition costs represents a net rate increase for customers – irrespective of whether these costs are recovered through the RES Tariff or recovered in base rates (or some combination of the two, as proposed in my direct testimony addressing revenue requirements).

Q. After taking account of the PSA credit being reset, and also taking account of the solar generation plant additions costs that are currently being recovered through the 2011 RES Adjustor, what is the net retail rate impact on APS customers from APS's proposed base rate increase relative to retail rates in effect at the end of 2011?

A. After taking into account that the 2011 RES Adjustor is currently recovering about $14.6 million of the $44.9 million in solar generation plant additions costs, the net retail rate increase from APS's proposed base rate increase

[6] Source: APS Response to AECC Data Request No. 3.1(f).

(as filed) and the resetting of the PSA credit to zero is $224.4 million, or 8.19%[7] on an overall basis, relative to retail rates in effect at the end of 2011. This number is derived from subtracting the $14.6 million current RES recovery from the $239 million rate impact identified just above.

Q. But will a greater proportion of solar generation plant additions costs be recovered in the 2012 RES Adjustor?

A. That is possible. APS has requested approval from the Commission to increase the 2012 RES Adjustor and part of that increase would be used to fund solar generation plant additions costs projected to be incurred in 2012. As of the date of this testimony, the Commission had not acted on this request.

To the extent that the Commission approves recovery of incremental solar plant additions costs through the 2012 RES Adjustor, then those costs would start to be recovered prior to the rate-effective period in this general rate case. As such, those costs would be removed from RES Adjustor if (and to the extent) that solar plant additions costs were approved for recovery in base rates as part of this case.

Q. Given that the net impact on customers from moving RES-eligible costs into base rates is uncertain and something of a moving target, what revenue requirement increase did you utilize as a baseline in developing a rate spread proposal?

A. In my rate spread proposal presented below, I use a baseline revenue requirement increase of $239 million, comprised of the sum of APS's proposed

[7] % Increase = Net Retail Increase ÷ [Present Base Rev. + PSA Reset Rev. + RES Solar Rev.]
% Increase = $224.4 ÷ [$2,868.9 + ($143.5) + $14.6] = 8.19%

base rate increase and PSA Reset, as discussed above. From a customer perspective, this baseline represents the "worst case scenario." Of course, the final rate increase in this case should be less than this: a number of parties, including AECC, have recommended significant reductions to APS's rate increase proposal. In addition, as I noted above, to the extent that rates are increased to recover incremental solar generation costs *prior* to the rate-effective period in this case, then some portion of any base rate increase associated with solar generation plant additions can be offset through a reduction in the RES Adjustor.

As discussed below, although the principles in my rate spread proposal are illustrated using the $239 million increase, these principles can be applied to any smaller revenue requirement increase that is adopted.

RATE SPREAD

Q. What general guidelines should be employed in spreading any change in rates?

A. In determining rate spread, or revenue apportionment, it is important to align rates with cost causation, to the greatest extent practicable. Properly aligning rates with the costs caused by each customer group is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

At the same time, it can be appropriate to mitigate the impact of moving immediately to cost-based rates for customer groups that would experience significant rate increases from doing so. This principle of ratemaking is known as "gradualism." When employing this principle, it is important to adopt a long-term strategy of moving in the direction of cost causation, and to avoid schemes that result in permanent cross-subsidies from other customers.

Q. What has APS proposed with respect to rate spread?

A. APS's proposed rate spread is discussed by APS witness Charles A. Miessner and is presented in APS Schedule H-2 and is restated in Table KCH-3, below, along with APS's cost-of-service results. The rate changes shown in Table KCH-3 are for *base rates only*, consistent with APS's presentation in Schedule H-2. I also present in Table KCH-4 the combined rate impacts of APS's proposed base rate change and the PSA Rest, which, as I have stated, provides greater insight than viewing base rate changes in isolation, and therefore is a better tool for determining a reasonable rate spread.

Table KCH-3

Comparison of APS Cost-of-Service Results to APS Proposed Rate Change Base Rates Only

Class	Base Rate Change per APS COS	APS Proposed Base Rate Change	Difference Between Proposed Rate & Cost
Residential	12.40%	3.95%	(8.45)%
General Service	(6.80)%	2.64%	9.44%
E-20	24.60%	3.89%	(20.72)%
E-32 (total)	(8.13)%	2.53%	10.66%
E-32 TOU	(11.13)%	2.60%	13.73%
E-30, E-32XS, S	(11.35)%	2.22%	13.57%
E-32M	(6.69)%	2.77%	9.46%
E-32L	(4.09)%	2.77%	6.87%
E-34	(0.25)%	3.07%	3.32%
E-35	0.95%	3.37%	2.42%
Water Pumping	9.18%	3.62%	(5.56)%
Outdoor Lighting	11.19%	3.62%	(7.57)%
Dusk-to-Dawn	(2.52)%	2.94%	5.46%
Total	3.33%	3.33%	0.00%

Table KCH-4

Comparison of APS Cost-of-Service Results to APS Proposed Rate Change
Combined Impact of Base Rates and PSA Reset

Class	Rate Change per APS COS	APS Proposed Rate Change	Difference Between Proposed Rate & Cost
Residential	17.66%	8.82%	(8.84)%
General Service	(1.27)%	8.73%	10.00%
E-20	31.18%	9.37%	(21.81)%
E-32 (total)	(3.03)%	8.23%	11.25%
GS TOU	(5.07)%	9.60%	14.67%
E-30, E-32XS, S	(7.35)%	6.84%	14.19%
E-32M	(1.25)%	8.76%	10.01%
E-32L	2.46%	9.80%	7.33%
E-34	7.47%	11.05%	3.58%
E-35	9.69%	12.31%	2.63%
Water Pumping	16.47%	10.54%	(5.93)%
Outdoor Lighting	15.33%	7.48%	(7.85)%
Dusk-to-Dawn	(0.98)%	4.56%	5.55%
Total	8.77%	8.77%	0.00%

As shown in Table KCH-3, APS's cost-of-service analysis shows the Residential class as warranting a base rate increase of 12.40 percent (at the Company's proposed revenue requirement), but receiving a base rate increase of just 3.95 percent. (As shown in Table KCH-4, when the effect of the PSA Reset is taken into account, the cost-based rate increase warranted by the Residential class at APS's proposed revenue requirement is 17.76 percent, and the proposed effective increase is 8.82 percent.)

At the same time, General Service customers are shown as warranting a base rate <u>decrease</u> of 6.80 percent (at the Company's proposed revenue requirement), but receiving a base rate <u>increase</u> of 2.64 percent. (When the effect of the PSA Reset is taken into account, the rate change warranted by the General

Service class is a reduction of 1.27 percent, and the proposed effective increase is 8.73 percent.) The upshot is that the cost-based rate change warranted by these two major groupings of customers is separated by more than 19 percentage points, but the base rate increase proposed by APS for these two groups is within 1.5 percentage points – and the effective rate increase (taking into account the PSA Reset) is virtually identical.

Q. What is your assessment of APS's rate spread proposal?

A. APS's proposed rate spread largely ignores cost of service ratemaking principles, while greatly expanding the very sizable subsidy that General Service customers pay to Residential customers. I calculate the proposed subsidy to be nearly $124 million per year.[8]

In my opinion, the Company's proposed rate spread does not reasonably reflect cost of service and should be rejected by the Commission. While the current economic climate is difficult for all customer classes, the magnitude of the inter-class subsidization in APS's proposal is an especially unreasonable burden to place upon the customers in the General Service class.

Q. Do you have an alternative rate spread recommendation?

A. Yes. I propose an approach that moves further in the direction of cost-of-service, while adhering to the principle of gradualism and providing continued rate mitigation for the Residential class. My proposal is summarized in the following five steps:

(1) Set Residential rates midway between system average percentage rate increase and the percentage increase necessary to bring Residential base rates to

[8] See Attachment KCH-6.

cost-of-service (taking into account the effect of the PSA Reset). This results in an overall rate increase for Residential customers that is within 5 percentage points of the system average rate increase.

(2) Cap the rate increase for other classes at 5 percentage points above the system average rate increase (taking into account the effect of the PSA Reset).

(3) Set Rate Schedules E-34 and E-35 (collectively) equal to cost-of-service, with both rate schedules receiving equal percentage increases (inclusive of the effect of the PSA Reset).

(4) Set the percentage increase for all remaining rate schedules (e.g., E-32, Dusk-to-Dawn) equal to the respective cost-of-service for each, plus the same percentage point increase necessary to fund the mitigation for Residential customers and the customer classes subject to the 5 percent cap.

(5) Within the E-32 grouping, apply the same percentage rate change to Rate Schedules E-32-M and E-32-L, as proposed by APS, in order to retain the same rate relationship between these two subgroups; at the same time, constrain the small commercial customer group (consisting of Rate Schedules E-30, E-32-XS, and E-32-S) such that its overall rate increase (inclusive of the effect of the PSA Reset) does not fall below zero, with any resulting revenues distributed among the remaining E-32 rate schedules on a pro-rata basis.

Q. What is the rate spread that is obtained from your recommended approach at APS's proposed revenue requirement?

A. These results are presented in Attachment KCH-7, and summarized in Tables KCH-5 and KCH-6, below.

Table KCH-5

Comparison of AECC Rate Spread to APS Rate Spread
Base Rates Only
At APS's Proposed Revenue Requirement

Class	Base Rate Change per APS COS	APS Base Rate Change	AECC Base Rate Change
Residential	12.40%	3.95%	8.15%
General Service	(6.80)%	2.64%	(2.12)%
E-20	24.60%	3.89%	8.06%
E-32 (total)	(8.13)%	2.53%	(2.58)%
GS TOU	(11.13)%	2.60%	(5.65)%
E-30, E-32XS, S	(11.35)%	2.22%	(4.32)%
E-32M	(6.69)%	2.77%	(1.04)%
E-32L	(4.09)%	2.77%	(1.04)%
E-34	(0.25)%	3.07%	0.94%
E-35	0.95%	3.37%	0.09%
Water Pumping	9.18%	3.62%	6.65%
Street Lighting	11.19%	3.62%	9.68%
Dusk-to-Dawn	(2.52)%	2.94%	3.24%
Total	3.33%	3.33%	3.33%

Table KCH-6

Comparison of AECC Rate Spread to APS Rate Spread
Combined Impact of Base Rates and PSA Reset
At APS's Proposed Revenue Requirement

Class	Combined Rate Change per APS COS	APS Combined Rate Change	AECC Combined Rate Change
Residential	17.66%	8.82%	13.21%
General Service	(1.27)%	8.73%	3.69%
E-20	31.18%	9.37%	13.77%
E-32 (total)	(3.03)%	8.23%	2.83%
GS TOU	(5.07)%	9.60%	0.78%
E-30, E-32XS, S	(7.35)%	6.84%	0.00%
E-32M	(1.25)%	8.76%	5.21%
E-32L	(2.46)%	9.80%	5.21%
E-34	7.47%	11.05%	8.75%
E-35	9.69%	12.31%	8.75%
Water Pumping	16.47%	10.54%	13.77%
Street Lighting	15.33%	7.48%	13.77%
Dusk-to-Dawn	(0.98)%	4.56%	4.87%
Total	8.77%	8.77%	8.77%

Q. **Please explain the basis for your proposal to move Residential rates halfway to cost of service.**

A. In my opinion, moving Residential rates halfway to cost of service strikes a reasonable balance between setting rates based on cost while taking into consideration the principle of gradualism. This rate spread results in an overall rate increase for Residential customers that is less than 5 percentage points above the system average rate increase, which is the rate impact cap I am recommending for all other customers.

Q. **Please explain the basis for your proposed 5 percent cap for other rate schedules.**

A. The rates for the capped classes are significantly below cost of service. I recommend that rates for these classes be moved closer to cost, while, at the same time, in the interest of gradualism, I am recommending capping the overall rate increase for these two classes at five percentage points above the system average base rate increase. So, for example, at APS's proposed rate increase of 8.77 percent (inclusive of PSA Reset), the maximum overall rate increase for any rate schedule would be capped at 13.77 percent.

Q. Please explain the basis for your proposed treatment of Rate Schedules 34 and 35.

A. Rate Schedules 34 and 35 serve customers with demands greater than 3,000 kilowatts. The difference between the two rate schedules is that the charges for Rate 35 are differentiated on a time-of-use ("TOU") basis, whereas the charges for Rate 34 are not. Because these two rate schedules serve the same set of eligible customers, it is important to maintain a rational relationship between their respective designs. For example, it would make no sense to reduce Rate 34 significantly relative to Rate 35, so as to force Rate 35 customers to abandon TOU pricing and migrate to the flat energy charges of Rate 34. For this reason, I recommend treating the two rate schedules on a collective basis for rate spread purposes. Specifically, I am recommending that rates for these two rate schedules be set, collectively, equal to their cost of service, such that there is no subsidy in or out of this group. Further, in order to maintain the pricing relationship between these two rate schedules, I am recommending that each receives the same percentage increase (taking into account the effect of the PSA Reset).

Q. Please explain the basis for your proposed treatment within the E-32 grouping in your fifth step.

A. E-32 customers migrate between E-32-M and E-32-L as their demand usage falls above or below 400 kW. The relationship between the current rates of these rate schedules and their respective costs of service is similar. APS had proposed an identical base rate percentage change for these two rate schedules. In my proposal, I adopt the same concept, but apply it to the rate change inclusive of the PSA Reset. With respect to my recommendation for the small customer grouping, I note that after completing the first four steps of my recommended rate spread, this group would receive an overall rate reduction of $7 million at APS's proposed overall revenue requirement – even after taking into account the effect of the PSA Reset. In light of the substantial overall rate increase proposed by APS in this case, it is reasonable to constrain the overall rate change to this group to zero. I recommend that the monies resulting from this constraint be used within the E-32 group to offset part of the large subsidy paid by E-32 customers to other classes.

Q. What approach to rate spread should be adopted if the Company's requested revenue requirement is reduced by the Commission?

A. If the Company's requested rate increase is reduced by the Commission, I recommend that the same five steps I described above be applied to the reduced revenue requirement.

Q. Steps 1 and 3 of your recommended rate spread approach are tied to the cost-of-service results at the approved revenue requirement. How should

your rate spread approach be applied if APS's cost-of-service study is not updated to reflect a reduced revenue requirement?

A. In such a case, my recommended rate spread approach can be reasonably approximated by using the <u>revenue apportionment</u> produced by the rate spread shown in Table KCH-6 (which is applied to APS's proposed revenue requirement) as the basis for spreading the smaller revenue change.

Q. Please explain this point further.

A. When I refer to the "revenue apportionment produced by the rate spread shown in Table KCH-6" I am referring to each class's percentage share of total base revenue requirement that results from that spread. For example, under my proposed spread, Residential customers would pay 53.64 percent of the total base revenue requirement (see Attachment KCH-8). If the Commission agrees that this proposed rate spread is reasonable, then by extension, the corresponding revenue apportionment is reasonable as well.

The rate spread at a reduced revenue requirement would be determined by retaining the percentage revenue apportionment that results from my recommended rate spread at APS's proposed revenue requirement (Table KCH-6) and applying this revenue apportionment to the final revenue requirement approved by the Commission.

Q. Do you have an example to illustrate how your approach would work?

A. Yes. An example is presented in Attachment KCH-8. In this example, the revenue apportionment associated with my proposed rate spread at APS's proposed revenue requirement is first determined. Next, we assume that the Commission reduces APS's proposed revenue increase by $75 million. The resulting rate spread is then calculated by holding the revenue apportionment constant. The results are summarized in Table KCH-7, below. [9]

Table KCH-7

Illustration of AECC Recommended Rate Spread Approach
Example Illustrating $75 Million Revenue Reduction to APS's Revenue Proposal

Class	Base Rate Change	Rate Change Inc. PSA Reset
Residential	5.42%	10.35%
General Service	(4.59)%	1.07%
E-20	5.33%	10.89%
E-32 (total)	(5.05)%	0.23%
GS TOU	(8.04)%	(1.77)%
E-30, E-32XS, S	(6.74)%	(2.53)%
E-32M	(3.10)%	2.55%
E-32L	(4.01)%	2.55%
E-34	(1.61)%	6.00%
E-35	(2.44)%	6.00%
Water Pumping	3.95%	10.89%
Street Lighting	6.91%	10.89%
Dusk-to-Dawn	0.63%	2.22%
Total	0.71%	6.02%

As shown in Table KCH-7, using a revenue apportionment approach results in each rate schedule *retaining its basic relationship to the* system average increase as occurs in the initial spread at APS's proposed revenue requirement; that is, the Residential class remains within 5 percentage points of the system average increase; capped classes remain approximately 5 percentage points above

[9] Note that the rate spread in Table KCH-7 shows some rate schedules receiving a rate decrease after taking account of the PSA Reset even though my proposal places a floor of 0% on the minimum rate increase – at APS's proposed revenue requirement. As APS's proposed revenue requirement is reduced, this constraint can either be retained – or relaxed – based on the Commission's assessment of whether a net rate decrease for some customers is reasonable in light of the size of the overall increase ultimately allowed (inclusive of the PSA Reset).

the system average increase; and the subsidy-paying classes retain approximately the same percentage differential below the system average increase as occurs in the initial spread at APS's proposed revenue requirement.

This consistency makes the revenue apportionment approach a useful tool for adjusting rate spread when a Commission reduces the revenue requirement from the utility's proposal, but the class cost-of-service study is not also simultaneously updated to reflect this reduction.

INTERRUPTIBLE RATE RIDER

Q. What is APS proposing with respect to an Interruptible Rate Rider?

A. As discussed by Mr. Miessner, APS is proposing the adoption of Rate Rider Schedule IRR, which would offer interruptible service to extra-large general service customers that can interrupt at least 500 kW of load when requested by APS. Rate Rider Schedule IRR would offer the customer a combination of options for participation.

Q. What is your assessment of APS's proposal to adopt Rate Rider Schedule IRR?

A. I support the adoption of Rate Rider Schedule IRR, but with modifications. If structured properly, interruptible rates can be a cost-effective means for utilities to obtain reliable capacity. In my opinion, it is important for interruptible service to be included in APS's resource mix, as it can provide benefits for both the Company as well as the customers with the operational flexibility to perform under an interruptible rider. Indeed, the inclusion of an APS interruptible rider was approved in concept as part of Decision 71448 approving the Settlement Agreement in APS's previous rate case. APS's proposal in this docket simply represents the implementation of this conceptual approval.

Q. What modifications do you recommend to Rate Rider Schedule IRR?

A. I recommend changing the basis of the credit paid to participating customers from "50% demand / 50% energy" as proposed by APS to "100% demand." I also recommend that the Rider include a multiyear schedule of capacity rates, rather than a single rate that will stand until the next general rate case.

Q. Please explain your first recommended modification.

A. APS's approach understates the value of the capacity being provided by participating customers by half. APS indicates that the gross value of the capacity that would be provided by interruptible customers in 2012 is $21.07 per kW-year (including losses).[10] (To put this in perspective, APS proposes to *charge* E-34 customers more than $126 per kW-year for generation capacity in 2012.) The gross value of this avoided capacity cost is then reduced to a factor of 56.9% or 76.7% (depending on the interruption option selected by the customer) to account for the more limited availability of interruptions relative to generation capacity.

I do not object to the reasonableness of these factors. However, APS then goes on to propose that only 50 percent of the credit paid to participating customers be recognized as a credit against the customer's demand charge and 50 percent paid out as an energy credit for actual interruptions. This approach understates the value of the capacity provided by participants (which is already being assigned a relatively low gross valuation to start with). The product that

[10] Source: APS Data Response to Staff 3.066.

interruptible customers are offering is capacity: indeed the value of their payment is derived strictly from the value of avoided capacity. Therefore, it is appropriate that 100 percent of the credit paid to participating customers be in the form of a demand credit, rather than just 50 percent. This problem can be corrected by eliminating the proposed energy credit and doubling the proposed demand credit.

Q. Please explain your proposed modification regarding a multiyear credit schedule.

A. The one-year credit proposed by APS is based on 2012 estimates of avoided capacity cost. However, APS's projected value of avoided capacity increases each year. While these increasing avoided capacity values are reflected in the five-year option proposed by APS, there is no provision for them to be reflected in the one-year option. As APS typically does not file a rate case each year, the one-year capacity credit will become stale. It makes sense to be sending the right price signal for this capacity; if it is expected to become more valuable going forward, that should be reflected in the Rider through a multiyear pricing provision – until superseded in a subsequent rate case.

Q. What is your recommendation to the Commission with respect to proposed Rate Rider Schedule IRR?

A. I recommend that the Commission approve Rate Rider Schedule IRR, but with the two modifications I recommended above.

EXPERIMENTAL RATE RIDER AG-1

Q. What is APS's proposal for Experimental Rate Rider AG-1?

A. As presented by Mr. Miessner, Experimental Rate Rider AG-1 would allow an E-34 or E-35 customer with an average monthly demand of 10 MW or more to obtain an alternative source of generation to serve its full power requirements. APS will purchase and manage the generation on behalf of the customer for a management fee of $0.0006 per kWh. APS will also provide scheduling, and if necessary, load following service.

Q. What is your assessment of the Company's proposal for Experimental Rate Rider AG-1?

A. The new product offering described by APS is sometimes called a "buy-through." This product has a similarity to direct access service, but the utility (in this case APS) acts as the middleman between customer and the market, rather than an Electric Service Provider ("ESP") playing this role.

In general, I support APS's proposal to make this option available to customers.

Q. Do you believe that Experimental Rate Rider AG-1 can be a good substitute for a policy of reinstating direct access service in Arizona?

A. No. AECC continues to advocate for a reactivation of direct access service in Arizona. I see the Experimental Rate Rider AG-1 proposed by APS as complementary to direct access service in that it would provide a means through which certain qualifying customers can gain access to market generation. This is a potentially valuable option that is not available to APS customers today due to the de facto suspension on Electric Service Provider ("ESP") certification approvals. While I support approval of this proposed rider, this limited buy-through approach still falls short of providing the potential benefits to customers that can occur from reinstating direct access service, which would be available to a broader range of customers and market participants.

Q. What benefits would accrue to customers from reinstating direct access service in Arizona?

A. Broadly speaking, customers would be able to avail themselves of market-priced power, which can be shaped by an ESP to fit the customer's time horizon and risk tolerance. It would also open the playing field to new market participants, who would bring their own competitive attributes. Direct access would also allow interested customers to acquire a wider range of renewable energy products to further their corporate or organizational objectives.

Q. Are there any specific terms in Experimental Rate Rider AG-1 that you propose to change?

A. Yes. The proposed Rider includes a provision for a "Reserve Capacity Charge" equal to 15 percent of the customer's monthly peak load. However, the Rider also requires that the product provided by the Generation Service provider be firm service. Firm service must be backed by reserves. Thus, the customer is already paying for reserves and it appears that the Reserve Capacity Charge would force the customer to pay twice for them. This double-charge is unwarranted. Moreover, the rate for the proposed Reserve Capacity Charge is not specified in the Rider, which is problematic.

Q. What is your recommendation to the Commission regarding the Experimental Rate Rider AG-1?

A. I recommend that it be approved by the Commission, but the requirement to pay a Reserve Capacity Charge should be removed. I also recommend that Experimental Rate Rider AG-1 should not be viewed as a substitute for reinstating full direct access service in Arizona.

<u>RATE DESIGN FOR RATE SCHEDULE E-32-L</u>

Q. What change APS proposed with respect to rate design for Rate Schedule E-32-L?

A. As discussed by Mr. Miessner, APS is proposing to remove the first tier energy charge for this rate schedule, modify the remaining energy charge to reflect the average energy cost per kWh, and to revise the demand charge to include the implicit demand-related costs that are currently recovered through the first tier energy charge.

Q. Do you support this rate design change?

A. Yes, I do. A demand charge is the preferred vehicle for recovery of demand-related costs for customers of this size. This change will make the structure of the E-32-L rate more closely aligned with that of Rate Schedule E-34.

Q. Does this restructuring of the design for Rate Schedule E-32-L lend support to your argument in your revenue-requirements testimony that customers on this rate schedule should be exempt from decoupling (if decoupling is adopted)?

A. Yes, it does. This rate redesign effectively removes fixed cost recovery from the E-32-L energy charge, which means that if E-32-L customers reduce their energy usage due to improved efficiency, it should not significantly impact APS's fixed cost recovery. Consequently, the premise for including these customers in any decoupling scheme is further weakened.

RATE DESIGN FOR RATE SCHEDULES E-34 AND E-35

Q. Do you have any concerns regarding the rate design for Rate Schedules E-34 and E-35?

A. Yes, I do. As I discussed above regarding rate spread, APS has focused its case on changes in base rates, without a great deal of consideration given to the fact that customers will be impacted through the elimination (or substantial reduction) of the PSA credit that will accompany the establishment of new rates. This issue has implications for rate design.

Specifically, in the case of E-34 and E-35 customers, APS is proposing what appears to be a small increase in the *base* energy charge, i.e., around 1%. However, this proposal ignores the fact that *real* energy charge paid by these customers today is some 15 percent lower than the base energy charge – due to the credit of $0.005658/kWh in the PSA. Thus, the 1% increase in the base energy charge proposed by APS is actually a **16% increase** in the overall energy rates paid by these customers. Such an increase is unreasonable; indeed, APS's fuel costs in base rates are going down, not up. The E-34 and E-35 energy charge should reflect this fact.

Q. If, as part of your rate design proposal, the E-34 and E-35 energy charges are reduced relative to what APS has proposed, does this cause costs to be passed to customers in other rate schedules?

A. No, not at all. If, as part of rate design, the E-34 and E-35 energy charge is reduced, the revenue is made up by increasing the E-34 and E-35 demand charges sufficiently to recover the revenue requirement assigned to these respective rate schedules.

Q. From a customer's perspective, why should it matter if the utility proposes a rate design that overprices the energy charge and understates the demand charge?

A. For a given rate schedule, when the energy charge is set above energy cost, and consequently demand-related charges are set below demand-related cost, those customers with relatively-higher load factors are required to subsidize the costs of the lower-load-factor customers within the rate class. In the case at hand, APS's proposed rate design would cause a greater rate overall rate increase (inclusive of the PSA Reset) on its higher-load-factor customers within E-34 and E-35 than on the lower-load-factor customers on those rate schedules. Since fuel costs are coming down, this disparate impact on higher-load-factor customers is unreasonable.

Q. What is your rate design recommendation for Rate Schedules E-34 and E-35?

A. I recommend that the energy charge for these two rate schedules be set equal to the current base energy rate *minus* the amount of the current credit in the

Forward Component of the PSA.[11] This price represents the current effective energy charges for these rate schedules, setting aside the Historical Component in the PSA. As fuel costs are declining, the energy charges for E-34 and E-35 customers should not be increased above this level.

Q. **Have you prepared an alternative rate design based on your recommendation?**

A. Yes. I have prepared an alternative rate design that implements my recommendation using APS's proposed revenue requirement for these two rate schedules. This is presented in Attachment KCH-9. If APS's revenue requirement for Rate Schedules E-34 and E-35 is reduced by the Commission, this same rate design approach can be applied to the lower revenue requirement; that is, the energy charge would be established as I describe above, and the demand charge would be set at a rate sufficient to recover the remaining revenue requirement.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

[11] The PSA Forward Component is currently $0.003016/kWh.

APS Proposed Rate Spread at APS's Requested Revenue Increase

(Base Rates Only)

APS Proposed Revenue Increase for each Customer Class

Line No.	Rate Class (a)	Current Retail Base Revenues[1] (b)	Rate Base[1] (c)	Return Req'd Return @ Equal ROR[1] (d)	Equalized Rate of Return (e) = (d) ÷ (c)	Equalized Relative Rate of Return (f) = (e) ÷ (e) Total	Required COS Revenue Increase[1] (g)	Fair Value Revenue Increase[1] (h) = (h) Total x Class Share of RB - Col. (c)	Req'd COS + Fair Value Revenue Increase (i) = (g) + (h)	Req'd Percent Change (j) = (i) ÷ (b)	APS Proposed Base Revenue Increase[2] (k)	APS Base Percent Change (l) = (k) ÷ (b)	APS Proposed Subsidy (m) = (i) - (k)	APS Proposed Subsidy Percent (n) = (m) ÷ (b)	Line No.
1	Residential	$1,470,133,000	$3,419,731,000	$303,330,000	8.87%	1.00	$157,824,000	$24,441,000	$182,265,000	12.40%	$58,104,000	3.95%	$124,161,000	8.45%	1
2	General Service														2
3	E-20	$3,886,000	$10,797,000	$958,000	8.87%	1.00	$879,000	$77,000	$956,000	24.60%	$151,000	3.89%	$805,000	20.72%	3
4	E-32 TOU (Combined)	$34,389,000	$44,976,000	$3,989,000	8.87%	1.00	($4,149,000)	$321,000	($3,828,000)	-11.13%	$894,000	2.60%	($4,722,000)	-13.73%	4
5 6	E-30, E-32 (0 - 20 kW) E-32 (21 - 100 kW)	$490,605,000	$852,781,000	$75,642,000	8.87%	1.00	($61,783,000)	$6,095,000	($55,688,000)	-11.35%	$10,911,000	2.22%	($66,599,000)	-13.57%	5 6
7	E-32 (101 - 400 kW)	$317,315,000	$521,011,000	$46,214,000	8.87%	1.00	($24,944,000)	$3,724,000	($21,220,000)	-6.69%	$8,791,000	2.77%	($30,011,000)	-9.46%	7
8	E-32 (401+ kW)	$303,798,000	$471,198,000	$41,795,000	8.87%	1.00	($15,807,000)	$3,368,000	($12,439,000)	-4.09%	$8,418,000	2.77%	($20,857,000)	-6.87%	8
9	E-30, E-32 Subtotal	$1,146,107,000	$1,889,966,000	$167,640,000	8.87%	1.00	($106,683,000)	$13,508,000	($93,175,000)	-8.13%	$29,014,000	2.53%	($122,189,000)	-10.66%	9
10	E-34	$80,597,000	$117,735,000	$10,443,000	8.87%	1.00	($1,043,000)	$841,000	($202,000)	-0.25%	$2,476,000	3.07%	($2,678,000)	-3.32%	10
11	E-35	$112,009,000	$140,920,000	$12,500,000	8.87%	1.00	$57,000	$1,007,000	$1,064,000	0.95%	$3,772,000	3.37%	($2,708,000)	-2.42%	11
12	General Service Total	$1,342,599,000	$2,159,418,000	$191,541,000	8.87%	1.00	($106,790,000)	$15,433,000	($91,357,000)	-6.80%	$35,413,000	2.64%	($126,770,000)	-9.44%	12
13	Water Pumping (E-38, E-221)	$26,669,000	$45,658,000	$4,050,000	8.87%	1.00	$2,122,000	$326,000	$2,448,000	9.18%	$966,000	3.62%	$1,482,000	5.56%	13
14	Outdoor/Street Lighting	$20,999,000	$67,341,000	$5,973,000	8.87%	1.00	$1,869,000	$481,000	$2,350,000	11.19%	$761,000	3.62%	$1,589,000	7.57%	14
15	Dusk to Dawn	$8,457,000	$28,130,000	$2,495,000	8.87%	1.00	($414,000)	$201,000	($213,000)	-2.52%	$249,000	2.94%	($462,000)	-5.46%	15
16	ACC Total	$2,868,857,000	$5,720,278,000	$507,389,000	8.87%	1.00	$54,611,000	$40,883,000	$95,493,000	3.33%	$95,493,000	3.33%	$0	0.00%	16

1. Data Source: ZJF_WP1 and 3 Adjusted Cost of Service Study TYE 12-31-2010
2. Data Source: APS SFR Schedule H-2

APS Proposed Rate Spread at APS's Requested Revenue Increase

(Combined Impact of Base Rates and PSA Credit Reset)

APS Proposed Revenue Increase for each Customer Class

	(a)	(b)	(c) Attach. KCH-6, p. 1, Col. (i)	(d)	(e) = (c) + (d)	(f) = (e) ÷ [(b) - (d)]	(g) Attach. KCH-6, p. 1, Col. (k) + (d)	(h) = (g) ÷ [(b) - (d)]	(i) = (e) - (g)	(j) = (i) ÷ (b)	
Line No.	Rate Class	Current Retail Base Revenues[1]	Required COS + Fair Value Revenue Increase	Reset of PSA Credit Increase[2]	Total COS + Fair Value with Reset of PSA Credit Increase	Req'd Percent Change	APS Proposed Revenue Increase with Reset of PSA Credit	APS Base Percent Change	APS Proposed Subsidy	APS Proposed Subsidy Percent	Line No.
1	Residential	$1,470,133,000	$182,265,000	$65,722,000	$247,987,000	17.66%	$123,826,000	8.82%	$124,161,000	8.45%	1
2	General Service										2
3	E-20	$3,886,000	$956,000	$195,000	$1,151,000	31.18%	$346,000	9.37%	$805,000	20.72%	3
4	E-32 TOU (Combined)	$34,389,000	($3,828,000)	$2,196,000	($1,632,000)	-5.07%	$3,090,000	9.60%	($4,722,000)	-13.73%	4
5	E-30, E-32 (0 - 20 kW)	$490,605,000	($55,688,000)	$21,204,000	($34,484,000)	-7.35%	$32,115,000	6.84%	($66,599,000)	-13.57%	5
6	E-32 (21 - 100 kW)										6
7	E-32 (101 - 400 kW)	$317,315,000	($21,220,000)	$17,484,000	($3,736,000)	-1.25%	$26,275,000	8.76%	($30,011,000)	-9.46%	7
8	E-32 (401+ kW)	$303,798,000	($12,439,000)	$19,444,000	$7,005,000	2.46%	$27,862,000	9.80%	($20,857,000)	-6.87%	8
9	E-30, E-32 Subtotal	$1,146,107,000	($93,175,000)	$60,328,000	($32,847,000)	-3.03%	$89,342,000	8.23%	($122,189,000)	-10.66%	9
10	E-34	$80,597,000	($202,000)	$5,790,000	$5,588,000	7.47%	$8,266,000	11.05%	($2,678,000)	-3.32%	10
11	E-35	$112,009,000	$1,064,000	$8,921,000	$9,985,000	9.69%	$12,693,000	12.31%	($2,708,000)	-2.42%	11
12	General Service Total	$1,342,599,000	($91,357,000)	$75,234,000	($16,123,000)	-1.27%	$110,647,000	8.73%	($126,770,000)	-9.44%	12
13	Water Pumping (E-38, E-221)	$26,669,000	$2,448,000	$1,670,000	$4,118,000	16.47%	$2,636,000	10.54%	$1,482,000	5.56%	13
14	Outdoor/Street Lighting	$20,999,000	$2,350,000	$754,000	$3,104,000	15.33%	$1,515,000	7.48%	$1,589,000	7.57%	14
15	Dusk to Dawn	$8,457,000	($213,000)	$131,000	($82,000)	-0.98%	$380,000	4.56%	($462,000)	-5.46%	15
16	ACC Total	$2,868,857,000	$95,493,000	$143,511,000	$239,004,000	8.77%	$239,004,000	8.77%	$0	0.00%	16

1. Data Source: ZJF_WP1 and 3 Adjusted Cost of Service Study TYE 12-31-2010
2. Data Source: APS Response to AECC Data Request No. 1.1

AECC Recommended Rate Spread at APS's Requested Revenue Increase

AECC Recommended Revenue Increase for each Customer Class based on APS's Cost of Service Study

E-20, Water Pumping & Outdoor/Streetlighting Adder above System Average Increase = 5.00%

Gen. Serv. TOU, E-30, E-32, Dusk to Dawn Adder Above Cost = 5.85%

	(a)	(b)	(c)	(d)	(g)	(h) = (g) ÷ (b)	(i)	(j) = (g) + (i)	(k) = (j) ÷ [(b) - (i)]	(l) = (m) x [(b) - (i)]	(m) = Input	(n) = (o) x [(b) - (i)]	(o) = Input	
Line No.	Rate Class	Current Retail Base Revenues[1]	Rate Base[1]	Return Req'd Return @ Equal ROR[1]	Req'd COS + Fair Value Revenue Increase[1]	Req'd Percent Change	Reset of PSA Credit Increase[2]	Req'd "COS" Base Revenue Increase	Req'd "COS" Base Percent Change	First Pass AECC Recommended Base Revenue Including Reset of PSA Credit Revenue	First Try AECC Base Percent Change Including Reset of PSA Credit	Second Pass AECC Recommended Base Revenue Including Reset of PSA Credit Revenue	Second Try AECC Base Percent Change Including Reset of PSA Credit	Line No.
1	Residential	$1,470,133,000	$3,419,731,000	$303,330,000	$182,265,000	12.40%	$65,722,000	$247,987,000	17.66%	$185,574,644	13.21%	$185,574,644	13.21%	1
2	General Service													2
3	E-20	$3,886,000	$10,797,000	$958,000	$956,000	24.60%	$195,000	$1,151,000	31.18%	$508,239	13.77%	$508,239	13.77%	3
4	E-32 TOU (Combined)	$34,389,000	$44,976,000	$3,989,000	($3,828,000)	-11.13%	$2,196,000	($1,632,000)	-5.07%	$252,527	0.78%	$252,527	0.78%	4
5 6	E-30, E-32 (0 - 20 kW) E-32 (21 - 100 kW)	$490,605,000	$852,781,000	$75,642,000	($55,688,000)	-11.35%	$21,204,000	($34,484,000)	-7.35%	($7,006,012)	-1.49%	$0	0.00%	5 6
7	E-32 (101 - 400 kW)	$317,315,000	$521,011,000	$46,214,000	($21,220,000)	-6.69%	$17,484,000	($3,736,000)	-1.25%	$13,815,630	4.61%	$30,460,248	5.21%	7
8	E-32 (401+ kW)	$303,798,000	$471,198,000	$41,795,000	($12,439,000)	-4.09%	$19,444,000	$7,005,000	2.46%	$23,650,631	8.32%			8
9	E-30, E-32 Subtotal	$1,146,107,000	$1,889,966,000	$167,640,000	($93,175,000)	-8.13%	$60,328,000	($32,847,000)	-3.03%	$30,712,775	2.83%	$30,712,775	2.83%	9
10	E-34	$80,597,000	$117,735,000	$10,443,000	($202,000)	-0.25%	$5,790,000	$5,588,000	7.47%	$6,548,635	8.75%	$6,548,635	8.75%	10
11	E-35	$112,009,000	$140,920,000	$12,500,000	$1,064,000	0.95%	$8,921,000	$9,985,000	9.69%	$9,024,365	8.75%	$9,024,365	8.75%	11
12	General Service Total	$1,342,599,000	$2,159,418,000	$191,541,000	($91,357,000)	-6.80%	$75,234,000	($16,123,000)	-1.27%	$46,794,014	3.69%	$46,794,014	3.69%	12
13	Water Pumping (E-38, E-221)	$26,669,000	$45,658,000	$4,050,000	$2,448,000	9.18%	$1,670,000	$4,118,000	16.47%	$3,442,281	13.77%	$3,442,281	13.77%	13
14	Outdoor/Street Lighting	$20,999,000	$67,341,000	$5,973,000	$2,350,000	11.19%	$754,000	$3,104,000	15.33%	$2,787,671	13.77%	$2,787,671	13.77%	14
15	Dusk to Dawn	$8,457,000	$28,130,000	$2,495,000	($213,000)	-2.52%	$131,000	($82,000)	-0.98%	$405,391	4.87%	$405,391	4.87%	15
16	ACC Total	$2,868,857,000	$5,720,278,000	$507,389,000	$95,493,000	3.33%	$143,511,000	$239,004,000	8.77%	$239,004,000	8.77%	$239,004,000	8.77%	16

1. Data Source: ZJF_WP1 and 3 Adjusted Cost of Service Study TYE 12-31-2010
2. Data Source: APS Response to AECC Data Request No. 1.1

AECC Recommended Rate Spread Approach
Example Illustrating a $75 Million Revenue Reduction to APS's Requested Increase
Including Reset of PSA Credit

Line No.	Rate Class (a)	Current Retail Base Revenues[1] (b)	PSA Credit Revenue (c)	Current Revenue Inclusive of PSA Credit (d) = (b) + (c)	AECC Recommended Base Revenue Increase Including Reset of PSA Credit Revenue (e) Attachment KCH-6 Column (n)	AECC Recommended Retail Base Revenue at APS' Requested Increase (f) = (d) + (e)	Revenue Apportionment Percentage (i) = (f) ÷ (f) Total	AECC Recommended Retail Base Revenue (j) = (i) x (j) Total	AECC Recommended Base Revenue Increase (k) = (j) - (d)	AECC Base Percent Change (l) = (k) ÷ (d)	Line No.
								Revenue Spread at Assumed $164 Million Increase			
1	Residential	$1,470,133,000	($65,722,000)	$1,404,411,000	$185,574,644	$1,589,985,644	53.64%	$1,549,757,964	$145,346,964	10.35%	1
2	General Service										2
3	E-20	$3,886,000	($195,000)	$3,691,000	$508,239	$4,199,239	0.14%	$4,092,995	$401,995	10.89%	3
4	E-32 TOU (Combined)	$34,389,000	($2,196,000)	$32,193,000	$252,527	$32,445,527	1.09%	$31,624,634	($568,366)	-1.77%	4
5	E-30, E-32 (0 - 20 kW)	$490,605,000	($21,204,000)	$469,401,000	$0	$469,401,000	15.83%	$457,524,847	($11,876,153)	-2.53%	5
6	E-32 (21 - 100 kW)										6
7	E-32 (101 - 400 kW)	$317,315,000	($17,484,000)	$299,831,000	$30,460,248	$614,645,248	20.73%	$307,482,687	$7,651,687	2.55%	7
8	E-32 (401+ kW)	$303,798,000	($19,444,000)	$284,354,000				$291,611,633	$7,257,633	2.55%	8
9	E-30, E-32 Subtotal	$1,146,107,000	($60,328,000)	$1,085,779,000	$30,712,775	$1,116,491,775	37.66%	$1,088,243,800	$2,464,800	0.23%	9
10	E-34	$80,597,000	($5,790,000)	$74,807,000	$6,548,635	$81,355,635	6.53%	$79,296,916	$4,489,916	6.00%	10
11	E-35	$112,009,000	($8,921,000)	$103,088,000	$9,024,365	$112,112,365		$109,276,217	$6,188,217	6.00%	11
12	General Service Total	$1,342,599,000	($75,234,000)	$1,267,365,000	$46,794,014	$1,314,159,014	44.33%	$1,280,909,928	$13,544,928	1.07%	12
13	Water Pumping (E-38, E-221)	$26,669,000	($1,670,000)	$24,999,000	$3,442,281	$28,441,281	0.96%	$27,721,698	$2,722,698	10.89%	13
14	Outdoor/Street Lighting	$20,999,000	($754,000)	$20,245,000	$2,787,671	$23,032,671	0.78%	$22,449,929	$2,204,929	10.89%	14
15	Dusk to Dawn	$8,457,000	($131,000)	$8,326,000	$405,391	$8,731,391	0.29%	$8,510,481	$184,481	2.22%	15
16	ACC Total	$2,868,857,000	($143,511,000)	$2,725,346,000	$239,004,000	$2,964,350,000	100.00%	$2,889,350,000	$164,004,000	6.02%	16

AECC Recommended Rate Design at APS's Requested Revenue Increase
General Service E-34 Rates
Test Year Ending Dec 31, 2010

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		APS (As Filed)[1]			AECC Proposed		
Line No.	Bundled Rates	Present	Proposed	% Change	Present	Proposed	% Change
1	*Basic Service Charge*						
2	Self-Contained	$ 1.135	$ 0.658	-42.0%	$ 1.135	$ 0.658	-42.0%
3	Instrument-Rated	$ 1.776	$ 1.328	-25.2%	$ 1.776	$ 1.328	-25.2%
4	Primary Voltage	$ 3.828	$ 3.477	-9.2%	$ 3.828	$ 3.477	-9.2%
5	Transmission Voltage	$ 26.161	$ 26.855	2.7%	$ 26.161	$ 26.855	2.7%
6	*Demand Charges:*						
7	Secondary Service	$ 17.377	$ 16.646	-4.2%	$ 17.377	$ 18.588	7.0%
8	Primary Service	$ 16.478	$ 15.687	-4.8%	$ 16.478	$ 17.629	7.0%
9	Transmission Service	$ 12.005	$ 10.914	-9.1%	$ 12.005	$ 12.856	7.1%
10	Primary substation - Military Base	$ 12.787	$ 11.749	0	$ 12.787	$ 13.691	
11	*Energy Charge*	$ 0.04220	$ 0.04258	0.9%	$ 0.04220	$ 0.03873	-8.2%
	Unbundled Rates						
12	*Basic Service Charge*						
13	*per day*	$ 0.601	$ 0.129	-78.5%	$ 0.601	$ 0.129	-78.5%
14	*Metering per day*						
15	Self-Contained	$ 0.395	$ 0.414	4.8%	$ 0.395	$ 0.4140	4.8%
16	Instrument-Rated	$ 1.036	$ 1.084	4.6%	$ 1.036	$ 1.0840	4.6%
17	Primary Voltage	$ 3.088	$ 3.233	4.7%	$ 3.088	$ 3.2330	4.7%
18	Transmission Voltage	$ 25.421	$ 26.611	4.7%	$ 25.421	$ 26.6110	4.7%
19	Meter Reading per day	$ 0.066	$ 0.038	-42.4%	$ 0.066	$ 0.0380	-42.4%
20	Billing per day	$ 0.073	$ 0.077	5.5%	$ 0.073	$ 0.0770	5.5%
21	Systems Benefit per kWh	$ 0.00210	0.00165	-21.4%	$ 0.00210	$ 0.00165	-21.4%
22	Transmission Charge						
23	Per kWh						
24	Per kW	$ 1.776	$ -	-100.0%	$ 1.776	$ -	-100.0%
25	Delivery Charge per kW;						
26	Secondary Service	$ 5.635	$ 6.012	6.7%	$ 5.635	$ 6.012	6.7%
27	Primary Service	$ 4.736	$ 5.053	6.7%	$ 4.736	$ 5.053	6.7%
28	Transmission Service	$ 0.263	$ 0.280	6.5%	$ 0.263	$ 0.280	6.5%
29	Primary substation - Military Base	$ 1.045	$ 1.115	6.7%	$ 1.045	$ 1.115	6.7%
30	Generation Charge						
31	Per kW	$ 9.966	$ 10.634	6.7%	$ 9.966	$ 12.576	26.2%
32	Per kWh	$ 0.04010	$ 0.04093	2.1%	$ 0.04010	$ 0.037083	-7.5%
33							
34	Delivery Discounts from Secondary Service ($/kW)						
35	Primary Service	$ 0.899	$ 0.959	0	$ 0.899	$ 0.959	
36	Transmission Service	$ 5.372	$ 5.732	0	$ 5.372	$ 5.732	
37	Primary substation - Military Base	$ 4.590	$ 4.897	0	$ 4.590	$ 4.897	

1. Data Source: APS Witness Miessner CAM_WP 13, Proof of Revenue

AECC Recommended Rate Design at APS's Requested Revenue Increase
General Service E-35 Rates
Test Year Ending Dec 31, 2010

Line No.	(a) Bundled Rates	(b) APS (As Filed)[1] Present	(c) APS (As Filed)[1] Proposed	(d) APS (As Filed)[1] % Change	(e) AECC Proposed Present	(f) AECC Proposed Proposed	(g) AECC Proposed % Change
1	*Basic Service Charge*						
2	Self-Contained	$ 1.183	$ 0.658	-44.4%	$ 1.183	$ 0.658	-44.4%
3	Instrument-Rated	$ 1.795	$ 1.328	-26.0%	$ 1.795	$ 1.328	-26.0%
4	Primary Voltage	$ 3.881	$ 3.477	-10.4%	$ 3.881	$ 3.477	-10.4%
5	Transmission Voltage	$ 26.574	$ 26.855	1.1%	$ 26.574	$ 26.855	1.1%
6	*Demand Charges:*						
7	Secondary Service						
8	On-Peak	$ 15.091	$ 14.351	-4.9%	$ 15.091	$ 16.606	10.0%
9	Off-Peak	$ 2.734	$ 2.945	7.7%	$ 2.734	$ 2.945	7.7%
10	Primary Service						
11	On-Peak	$ 14.343	$ 13.545	-5.6%	$ 14.343	$ 15.800	10.2%
12	Off-Peak	$ 2.659	$ 2.864	7.7%	$ 2.659	$ 2.864	7.7%
13	Transmission Service						
14	On-Peak	$ 10.483	$ 9.385	-10.5%	$ 10.483	$ 11.640	11.0%
15	Off-Peak	$ 2.273	$ 2.448	7.7%	$ 2.273	$ 2.448	7.7%
16	Primary Substation - Military Base						
17	On-Peak	$ 11.520	$ 10.502	-8.8%	$ 11.520	$ 12.757	10.7%
18	Off-Peak	$ 2.376	$ 2.559	7.7%	$ 2.376	$ 2.559	7.7%
19	*Energy Charge*						
20	On-Peak	$ 0.04694	$ 0.04749	1.2%	$ 0.04694	$ 0.04347	-7.4%
21	Off-Peak	$ 0.03530	$ 0.03559	0.8%	$ 0.03530	$ 0.03183	-9.8%
	Unbundled Rates						
22	Basic Service Charge	$ 0.601	$ 0.129	-78.5%	$ 0.601	$ 0.129	-78.5%
23	Revenue Cycle Service Charges						
24	Self Contained	$ 0.440	$ 0.414	-5.9%	$ 0.440	$ 0.414	-5.9%
25	Instrument-Rated	$ 1.052	$ 1.084	3.0%	$ 1.052	$ 1.084	3.0%
26	Primary Voltage	$ 3.138	$ 3.233	3.0%	$ 3.138	$ 3.233	3.0%
27	Transmission Voltage	$ 25.831	$ 26.611	3.0%	$ 25.831	$ 26.611	3.0%
28	Meter Reading	$ 0.068	$ 0.038	-44.1%	$ 0.068	$ 0.038	-44.1%
29	Billing	$ 0.074	$ 0.077	4.1%	$ 0.074	$ 0.077	4.1%
30	System Benefits Charge	$ 0.00210	$ 0.00165	-21.4%	$ 0.00210	$ 0.00165	-21.4%
31	Transmission Charge per kWh						
32	per On-Peak kW	$ 1.776	$ -	-100.0%	$ 1.776	$ -	-100.0%
33	*Delivery Charge*						
34	Secondary Service						
35	On-Peak	$ 4.951	$ 5.336	7.8%	$ 4.951	$ 5.336	7.8%
36	Off-Peak	$ 0.495	$ 0.534	7.9%	$ 0.495	$ 0.534	7.9%
37	Primary Service						
38	On-Peak	$ 4.203	$ 4.530	7.8%	$ 4.203	$ 4.530	7.8%
39	Off-Peak	$ 0.420	$ 0.453	7.9%	$ 0.420	$ 0.453	7.9%
40	Transmission Service						
41	On-Peak	$ 0.343	$ 0.370	7.9%	$ 0.343	$ 0.370	7.9%
42	Off-Peak	$ 0.034	$ 0.037	8.8%	$ 0.034	$ 0.037	8.8%
43	Primary Substation - Military Base						
44	On-Peak	1.38	$ 1.487	7.8%	1.38	$ 1.487	7.8%
45	Off-Peak	0.137	$ 0.148	8.0%	0.137	$ 0.148	8.0%
46	*Generation Charge*						
47	On Peak kW	$ 8.364	$ 9.015	7.8%	$ 8.364	$ 11.270	34.7%
48	Off Peak kW	$ 2.239	$ 2.411	7.7%	$ 2.239	$ 2.411	7.7%
49	On Peak kWh	0.04484	$ 0.04584	2.2%	0.04484	$ 0.04182	-6.7%
50	Off Peak kWh	0.03320	$ 0.03394	2.2%	0.03320	$ 0.03018	-9.1%
51							
52	Delivery Discounts from Secondary Service ($/kW)						
53	Primary Service	$ 0.748	$ 0.806	7.8%	$ 0.748	$ 0.806	7.8%
54	off peak	$ 0.075	$ 0.081	8.0%	$ 0.075	$ 0.081	8.0%
55	Transmission Service	$ 4.608	$ 4.966	7.8%	$ 4.608	$ 4.966	7.8%
56	off peak	$ 0.461	$ 0.497	7.8%	$ 0.461	$ 0.497	7.8%
57	Primary substation - Military Base	$ 3.913	$ 4.217	7.8%	$ 3.913	$ 4.217	7.8%
58	off peak	$ 0.255	$ 0.275	7.9%	$ 0.255	$ 0.275	7.9%

1. *Data Source: APS Witness Miessner CAM_WP 13, Proof of Revenue*